TECHNICAL REVIEW DOCUMENT
for
MODIFICATION TO OPERATING PERMIT 01OPAD212

Trigen-Colorado Energy Corporation Cogeneration Facility
At The Metro Wastewater Treatment Facility
Adams County
Source ID 0010097

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I. Purpose:

This document establishes the decisions made regarding the requested modifications to the Operating Permit for Trigen-Colorado. This document provides information describing the type of modification and the changes made to the permit as requested by the source and the changes made due to the Division=s analysis. This document is designed for reference during review of the proposed permit by EPA and for future reference by the Division to aid in any additional permit modifications at this facility. The conclusions made in this report are based on the information provided in the original request for modification submitted to the Division on May 17, 2004, additional information submitted June 24, 2004, comments on the draft permit and technical review document received on October 29, 2004, e-mail correspondence, and telephone conversations with the source.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Permit Modification Request/Modification Type

Trigen-Colorado has requested a modification to their Title V operating permit to replace the existing seven (7) flares with four (4) new flares. The new flares will be located to the south of the digester complex. The existing flares are currently located near digester vents and present a fire hazard. No changes to the annual emission or digester gas processing limits were requested with this modification. However, with this modification, the source has agreed to an hourly digester gas production/consumption limit and a lower H_2S limit on the digester gas.

Colorado Regulation No. 3, Part C, Section X.A identifies those modifications that can be processed under the minor permit modification procedures. Specifically, minor permit modifications "are not otherwise required by the Division to be processed as a significant modification" (Colorado Regulation No. 3, Part C, Section X.A.6). The Division requires that "any change that causes a significant increase in emissions" be processed as a significant modification (Colorado Regulation No. 3, Part C, Section I.B.36.h.(i)). Typically for determining whether the modification results in a "significant increase in emissions" for determining whether a modification request should be processed as a minor vs. significant modification, the Division looks at potential to emit (PTE). Since the permit does not provide any individual emissions limits for the combustion equipment, the PTE of the flare, would be considered the permit limits for the facility, which for PM_{10}, NO_X and SO_2 are above the PSD significance levels. Since the digester gas cannot be stored, the flares typically are only used when digester gas cannot be burned in the turbines or the engines, which is kind of an emergency situation. In fact, the permitted fuel (digester gas) consumption limit for the facility is based on both turbines running at 8760 hrs/yr plus an additional 149.5 mmSCF/yr, presumable for the flare.

Therefore, the Division considered that the test to determine whether the modification would result in a "significant emission increase" would be based on some method other than traditional PTE. Initially the Division considered that the PTE for the flares would be determined in the same manner as an emergency generator, i.e. that PTE would be based on 500 hrs/yr of operation. The flare fuel consumption for 500 hrs/yr was calculated and compared to historical actual fuel consumption for the flares to verify that the flares have historically been used rather infrequently. The Division calculated the fuel consumption of the new flares at 500 hrs/yr of operation to be 151.2 mmSCF/yr. The Division looked at 11 years of recent data and only 3 years indicated a flare fuel usage of more than 151.2 mmSCF/yr. For two of these years, the fuel consumption from the flares was 190 and 191.7 mmSCF/yr. Fuel consumption for the year 2000 was much higher than 151.2 mmSCF/yr, but that was the year the turbines were installed and is considered an anomaly. Therefore, the Division used the highest actual annual fuel usage (192 mmSCF/yr) to determine emissions to see if the minor modification procedures could be used. Using that approach emissions (at 1900 ppmvd H_2S, as initially requested) were as follows: PM_{10} – 0.07 tons/yr, SO_2 – 30.3 tons/yr and NO_X – 1.8 tons/yr. Since SO_2, NO_X and PM_{10} emissions at that fuel consumption limit are all below the PSD significance levels (40 tons/yr for NO_X and SO_2 and 15 tons/yr for PM_{10}), the Division considers that the modification request could be processed as a minor modification.

In addition, the Division requires that "any change that requires or changes a case-by-case determination of an emission limitation or standard" be considered a significant modification. Typically such changes would be modifying a BACT or RACT limit. Since the Denver metro area is now attainment/maintenance for the 1-hr ozone standard (VOC), CO and PM_{10}, the flares would be subject to RACT. RACT applies at any level for VOC, CO and PM_{10} and for NO_X and SO_2 (PM_{10} precursors), RACT only applies if emissions exceed 40 tons/yr. As discussed above, the Division considers that emissions from this modification do not exceed 40 tons/yr, therefore, RACT for SO_2 and NO_X do not apply. There is no de minimis for VOC, CO and PM_{10} RACT. Flares are often used to control VOC emissions, therefore, the addition of a control device to reduce VOC emissions from a flare would not be considered practical. In addition, for CO and PM_{10}, no add-on controls are practical for the flare. RACT for VOC and CO is determined to be good combustion practices. Performance tests to quantify emissions from flares are difficult to conduct; therefore, no emission limitations are associated with RACT for the flares. Since no add-controls or emission limitations will be required for RACT, the Division considers that this modification can be processed as a minor modification.

III. Modeling

Although no increase in annual emissions or digester gas consumption has been requested with this modification, because the location of the flare has changed modeling is necessary to determine whether the modification will cause or contribute to a violation of the national and Colorado ambient air quality standards (NAAQS/CAAQS). Modeling was conducted to determine if there were significant impacts from the relocation of the flares and the results of that analysis indicated that a cumulative modeling analysis was necessary. The results of the cumulative modeling analysis are as follows:

Pollutant	Averaging. Time	Proposed Mod ($\mu g/m^3$)	Proposed Mod and Nearby Sources ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	NAAQS/CAAQS ($\mu g/m^3$)
SO_2	3-hr	24.74	1,055.2*	49.8	1,105.0	1,300/700
SO_2	24-hr	14	301.1*	12.3	313.4	365/N/A

*highest-2nd –high concentration

Note that although there were several modeled violations of the state 3-hr SO_2 standard, the Metro Wastewater facility is not a significant contributor to any of the modeled violations (impacts < 25 $\mu g/m^3$).

IV. Discussion of Modifications Made

<u>Source Requested Modifications</u>

The Division addressed the source=s requested modifications as follows:

<u>Replacement of Existing Flares with New Flares</u>

The additional applicable requirements for the new flares are as follows:

- Hourly fuel consumption limit of 226.8 MSCF/hr, on a 3-hr rolling average (required to comply with the NAAQS/CAAQS)

- H_2S concentration of the digester gas not to exceed 1680 ppm (required to comply with the NAAQS/CAAQS)

- Construction of this source must commence within 18 months of initial approval permit issuance date or within 18 months of date on which such construction or activity was scheduled to commence as stated in the application (Reg 3, Part B, Section III.F.4.a.(i) thru (iii)).

- The permittee shall notify the Division, in writing, thirty (30) days prior to startup (Reg 3, Part B, Section III.G.1).

- Within 180 days after commencement of operation, compliance with the conditions contained on this permit shall be demonstrated to the Division (Reg 3, Part B, Section III.G.2).

- RACT for new flares

    - RACT for VOC (Reg 7, Section II.C.2).

    - RACT for PM_{10} and CO (Reg 3, Part B, Section III.D.3.a.(i))

    Note that as discussed previously, the Division considers that RACT for NO_X and SO_2 do not apply since the emission increase from this modification is presumed to be less than 40 tons/yr of NO_X and SO_2.

The source submitted a draft permit with the requested modification to replace the existing flares. The Division did not agree entirely with the language included in the draft permit and some revisions were made. The significant changes from the source's proposed draft permit are as follows:

- <u>Section I, Condition 1.1. source description.</u> In the proposed draft permit, the source included language stating that the provisions in the revised permit are not effective until the new flares are installed and a 30-day testing and startup period has elapsed. The Division believes this language is not appropriate and has removed it. The permit has been written to address the installation of the new flares and removal of the old flares.

- <u>Section II, Conditions 1.3.2.4, 1.3.3.2 and 2.3.2.</u> Rather than identify the H_2S concentration limit, the Division revised the language to reference the permit condition (Condition 1.8.1).

- <u>Section II, Condition 1.6.2, fuel monitoring language.</u> The Division revised the proposed draft permit language to indicate that the short-term limit does not apply until the new flares commence operation. The Division also revised the language in this condition regarding maintaining the flow meters. In addition, the Division included language in the permit requiring the source to operate the flow meters in accordance with a quality assurance/quality control plan and to make such plan available to the Division upon request.

- Section II, Condition 1.6.3, fuel monitoring language. The Division agrees with the source's proposed data substitution method and it has been included in the permit. In their comments on the draft permit, received on October 29, 2004, the source indicated that they no longer expected "non-obvious" malfunctions of the flow meters and the language regarding "sudden changes in total gas flow rate" and the use of the data replacement procedures "when there is a significant deviation in measured flow compared to expected normal operations" are not included in the permit.

- Section II, Condition 1.8.1. The Division revised this condition to indicate that the lower H_2S concentration limit does not apply until the new flares commence operation.

It should be noted that the source indicated that a testing period would be needed for the new flares. The source requested that for a period of 30 days after initial startup they would like to be able to use either the existing or new flares. The Division understands a testing period may be required for the flares to be fully operational and therefore will allow the 30-day testing period. However, it should be noted that the short-term digester gas consumption rate and lower H_2S concentration apply upon initial startup of the new flares, not after the 30 day testing period.

Other Modifications

In addition to the requested modifications made by the source, the Division used this opportunity to include changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this modification.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments on other permits, to the Trigen-Colorado Operating Permit with the source's requested modifications. These changes are as follows:

General

The Reg 3 citations were revised throughout the permit, as necessary, based on the recent revisions made to Reg 3.

Section I - General Activities and Summary

Revised Condition 1.1 to update the attainment status of the area.

In Condition 1.4, General Condition 3.g (Common Provisions, Affirmative Defense) was added as a State-only requirement.

<u>Section II.1 Turbines, Engines, Boilers and Flares</u>

<u>Lower vs. Higher Heating Value</u>

During the pre-application discussions, the source and Division became aware of various issues regarding the use of higher vs. lower heating value of the fuel. The current permit does not specify whether the emission calculations should be based on the lower or the higher heating value of the fuel. The Division considers that either the lower or the higher heating value may be used to calculate emissions, as long as the emission factor is on the same basis (i.e. if the emission factor is based on the lower heating value of the fuel, then the lower heating value of the fuel should be used to calculate emissions). In general, the emission factors in the current permit are based on AP-42, stack test data and manufacturer's data. The AP-42 emission factors are based on the higher heating value (HHV) of the fuel. The stack test data (in lbs/mmSCF) were converted to units of lbs/mmBtu based on the digester gas heat value of 656 Btu/scf, which is the HHV of the digester gas. The manufacturer's data (in lbs/hr) was converted to lbs/mmBtu based on the heat rate of the equipment provided on the manufacturer's data sheet, which based on LHV. Therefore, the basis for the emission factors is a mix of HHV and LHV. The source indicated that they would base emission calculations on the LHV for digester gas and the HHV for natural gas. Therefore, emission factors were converted as necessary using the following factors (based on a "rule of thumb"): HHV/LHV = 1.1 and LHV/HHV = 0.9, as discussed below.

<u>Turbines</u> – The emission factors for VOC, NO_X and CO are based on manufacturer's estimates (lbs/hr) and were converted to lbs/mmBtu based on the manufacturer's heat rate, which is LHV. The VOC, NO_X and CO emission factors for natural gas were converted to a HHV basis. In addition, the emission factors for PM and PM_{10}, when burning digester gas are from AP-42, which is based on HHV. The PM and PM_{10} emission factors when burning digester gas were converted to a LHV basis. See the below table for the emission factor changes (lightly shaded regions show the revised emission factors):

Fuel	Emission Factors (lb/mmBtu)				
	PM	PM_{10}	NO_X	CO	VOC
Digester gas					
Current Permit	1.2×10^{-2}	1.2×10^{-2}	0.232	0.129	0.037
This Draft	1.32×10^{-2}	1.32×10^{-2}	0.232	0.129	0.037
Natural Gas					
Current Permit	6.6×10^{-3}	6.6×10^{-3}	0.589	0.119	0.0683
This Draft	6.6×10^{-3}	6.6×10^{-3}	0.530	0.107	0.0615

<u>Engines</u> –The emission factors for burning digester gas are from stack testing, which are based on the HHV. Therefore, the emission factors for burning digester gas were

converted to a LHV basis. See the below table for the emission factor changes (lightly shaded regions show the revised emission factors):

	Emission Factor (lb/mmBtu)				
	PM	PM_{10}	NO_X	CO	VOC
Current Permit	7.36×10^{-3}	7.36×10^{-3}	0.308	0.454	2.19×10^{-4}
This Draft	8.10×10^{-3}	8.10×10^{-3}	0.339	0.499	2.41×10^{-4}

Flares – The emission factors for burning digester gas are from stack testing, which are based on the HHV. Therefore, the emission factors for burning digester gas were converted to a LHV basis. See the below table for the emission factor changes (lightly shaded regions show the revised emission factors):

	Emission Factor (lb/mmBtu)				
	PM	PM_{10}	NO_X	CO	VOC
Current Permit	1.23×10^{-3}	1.23×10^{-3}	3.33×10^{-2}	2.80×10^{-2}	5.39×10^{-3}
This Draft	1.35×10^{-3}	1.35×10^{-3}	3.66×10^{-2}	3.08×10^{-2}	5.93×10^{-3}

Boilers – The emission factors for natural gas burning are from AP-42 and are based on the HHV, therefore, no changes are necessary.

In addition to correcting the emission factors, the current permit does not include a requirement to determine the heating value of the fuel. Therefore, the Division included a requirement to analyze digester gas semi-annually to determine the heat content of the fuel. For natural gas, the source may base the heat value of the fuel on the tariff sheets.

Engines – 8-hr Ozone Control Area Requirements

Effective May 31, 2004, revisions were made to Colorado Regulation No. 7 to address VOC emissions from engines located in the 8-hr Ozone Control Area. This source is located in the Denver metro area, which is part of the 8-hr Ozone Control Area. The requirements for engines are in Section XVI and apply to any natural gas-fired reciprocating internal combustion engine with a manufacturer's design rate greater than 500 hp. The engines at the Metro facility are greater than 500 hp. In their comments on the draft permit submitted on October 29, 2004 Trigen requested that the permit be revised to restrict the engines from burning natural gas. Since the engines are no longer permitted to burn natural gas, the provisions in Colorado Regulation No. 7, Section XVI no longer apply. In addition, Trigen requested that the permit shield for the requirements in Colorado Regulation No. 7, Section XVI be granted since the engines will no longer be permitted to burn natural gas. The Division has revised the permit shield as requested.

Natural Gas Fuel Sampling for NSPS GG

Revisions to NSPS Subpart GG were published in the Federal Register (Volume 69, No. 13) on July 8, 2004. These revisions include alternative monitoring methods that EPA has approved on a case-by-case basis for other turbines over the years. Although EPA approved a natural gas custom fuel monitoring schedule for this source, the source may use the natural gas fuel sampling methods included in the revised NSPS GG. If a source is using gas that meets the definition of natural gas in 40 CFR Part 60 Subpart GG § 60.331(u), then no fuel sampling for sulfur content is required. The source may demonstrate that they are using natural gas based on either fuel sampling or the gas quality characteristics in a valid contract or tariff sheet from the gas supplier. The Division presumes that the source will make the demonstration using a tariff sheet, so this option will be included in the permit. The NSPS GG revisions also indicate that source that do not claim the fuel-bound nitrogen allowance are not required to monitor the nitrogen content of the gas. This will also be noted in the permit.

HAP Source Status and MACT Applicability

Case-by-Case MACT - 112(j) (40 CFR Part 63 Subpart B §§ 63.50 thru 63.56)

Under the federal Clean Air Act (the Act), EPA is charged with promulgating maximum achievable control technology (MACT) standards for major sources of hazardous air pollutants (HAPs) in various source categories by certain dates. Section 112(j) of the Act requires that permitting authorities develop a case-by-case MACT for any major sources of HAPs in source categories for which EPA failed to promulgate a MACT standard by May 15, 2002. These provisions are commonly referred to as the "MACT hammer".

Owners or operators that could reasonably determine that they are a major source of HAPs which includes one or more stationary sources included in the source category or subcategory for which the EPA failed to promulgate a MACT standard by the section 112(j) deadline were required to submit a Part 1 application to revise the operating permit by May 15, 2002. Metro Wastewater Reclamation District (OP No. 95OPAD072) submitted a Part 1 notification and indicated that the facility was a minor source for HAPS. Trigen submitted a Part 1 notification and indicated that based on a preliminary analysis, the source was minor for HAPS but requested that the Division confirm their applicability determination. The Division reviewed the HAP emissions for the facility and has determined that based on the information available, it appears that the facility is a minor source for HAPS (see table on page 11 of this document), with the highest single HAP at 7.12 tons/yr (toluene) and combined HAPS at 18.84 tons/yr. The HAP analysis included on page 11 was based on the potential to emit of HAPS provided by MWRD in December 1995. However, because VOC emissions from the wastewater treatment operations are permitted at 13.4 tons/yr, (operating permit No. 95OPAD072) issued to Metro Wastewater Reclamation District (MWRD)), potential emissions from a single HAP could exceed 10 tons/yr. Therefore, the Division considers that the facility is a major source for HAPS. It should be noted that if MWRD took a limit on HAP emissions from the wastewater treatment operations, the facility could become a synthetic minor source for HAPS.

Since the EPA has signed off on final rules for all of the source categories which were not promulgated by the deadline, the case-by-case MACT provisions in 112(j) no longer apply.

Combustion Turbine MACT (40 CFR Part 63 Subpart YYYY)

In accordance with 40 CFR Part 63 Subpart YYYY §63.6090(b)(4), existing (construction commenced prior to January 14, 2003) stationary combustion turbines do not have to meet the requirements of Subparts A and YYYY, including the initial notification requirements.

Reciprocating Internal Combustion Engines (40 CFR Part 63 Subpart ZZZZ)

In accordance with 40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3), existing (commenced construction or reconstruction prior to December 19, 2002) 4-stroke lean burn engines do not have to meet the requirements of Subparts A and ZZZZ, including the initial notification requirements.

Industrial, Commercial and Institutional Boilers and Process Heaters MACT (40 CFR Part 63 Subpart DDDDD)

The final rule for industrial, commercial and institutional boilers and process heaters was signed on February 26, 2004 and was published in the Federal Register on September 13, 2004. Based on the final rule, large (> 10 mmBtu/hr) existing (constructed or reconstructed prior to January 13, 2003) gaseous fuel boilers or process heaters do not have to meet the requirements of Subparts A and DDDDD, except for the initial notification requirements, as specified in 40 CFR Part 63 Subpart DDDDD § 63.7506(b)(1). The initial notification requirement has been included in the revised permit for the boilers.

In addition, existing small (≤ 10 mmBtu/hr) gaseous fuel boilers or process heaters do not have to meet the requirements of Subparts A and DDDDD, including the initial notification requirements, as specified in 40 CFR Part 63 Subpart DDDDD § 63.7506(c)(3).

Section IV – General Conditions

General Condition No. 3 was revised to reflect that 3.g (affirmative defense) is state-only until approved by EPA.

Appendices

As requested in their comments on the draft permit (October 29, 2004), added the new flare pilot lights to the insignificant activity list.

In the previous modification, the Division included the back-up H_2S continuous monitoring system (in Section II, Condition 2.3) but did not identify this change in Appendix F. Appendix F was revised to indicate this change was made with the previous modification.

Total HAP Emissions from Metro Wastewater Facility

		Source			
Pollutant	**NG Combustion[1]**	**DG Combustion[2]**	**WW Treatment[3]**	**MWRD Emerg. Gen[4]**	**Total**
acetaldehyde		5.803E-02		1.09E-04	5.814E-02
acrolein		3.482E-02		3.40E-05	3.485E-02
benzene	1.008E-04	1.562E-00		3.35E-03	1.565E-00
cadmium	5.288E-05				5.288E-05
chlorobenzene			1.30E-01		1.300E-01
chloroethane (ethyl chloride)			1.00E-01		1.000E-01
chloroform			4.10E-01		4.100E-01
chromium	6.720E-05				6.720E-05
dichlorobenzene	5.760E-05				5.760E-05
ethylbenzene			4.50E-01		4.500E-01
formaldehyde	3.600E-03	1.310E-01		3.41E-04	1.349E-01
hexane	8.640E-02				8.640E-02
methylene chloride		6.107E-02	1.56E-00		1.621E-00
methanol					0.000E+01
naphthalene	2.928E-05				2.928E-05
nickel	1.008E-04				1.008E-04
styrene		3.410E-02			3.410E-02
TCA (methylene chloride)		5.567E-02	2.20E-01		2.757E-01
TCE			4.60E-01		4.600E-01
tetrachloroethylene (perchloroethylene)			3.00E-00		3.000E-00
toluene	1.632E-04	4.886E-02	7.05E-00	1.21E-03	7.100E-00
vinyl chloride					0.000E+01
xylene				8.33E-04	8.329E-04
Total	0.09	1.99	13.38	0.01	15.46

[1]based on boilers burning natural gas at permitted annual limit, using AP-42 emission factors
[2]based on the flares burning digester gas at permitted rate, emission factors from FIRE (used boiler emission factors)
[3]based on 12/20/95 HAP summary from MWRD
[4]based on max hrly fuel and permitted hrs of operation.